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C. DUKES SCOTT
EXECUTIVE DIRECTOR

OFFICE OF REGULATORY STAFF
ORS
SOUTH CAROLINA

DAN F. ARNETT
CHIEF OF STAFF

P.O. Box 11263
Columbia, S.C. 29211

Phone: (803) 737-0800
Fax: (803) 737-0801

July 31, 2006

VIA HAND DELIVERY

Mr. Charles L.A. Terreni
Chief Clerk/Administrator
South Carolina Public Service Commission
101 Executive Center Dr., Suite 100
Columbia, SC 29210

Re: Duke Power - Annual Review of Base Rates for Fuel Costs.
Docket No. 2005-3-E

Dear Mr. Terreni:

Enclosed for filing please find the original and one (1) copy of the **REDACTED FUEL STUDY** and the original and one (1) copy of the **UNREDACTED FUEL STUDY** in the above referenced matter. Please date stamp the extra copy enclosed and return it to me in the envelope provided.

Also, we have served same on Counsel for the Applicant and enclose a Certificate of Service to that effect.

Please let me know if you have any questions.

Sincerely,

C. L. H.

C. Lessie Hammonds

CLH/pjm
Enclosures
cc: Lara Simmons Nichols, Esquire
Richard L. Whitt, Esquire
Scott Elliott, Esquire

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2005-3-E

IN RE:

Duke Power – Annual Review of	)	
Base Rates for Fuel Costs	)	**CERTIFICATE OF SERVICE**
	)	
______________________________	)	

This is to certify that I, Pamela J. McMullan, an employee with the Office of Regulatory Staff, have this date served one (1) copy of the **REDACTED FUEL STUDY** in the above-referenced matter to the person(s) named below by causing said copy to be deposited in the United States Postal Service, first class postage prepaid and affixed thereto, and addressed as shown below:

Lara Simmons Nichols, Assistant General Counsel
Duke Energy Corporation
PO Box 1006 (EC03T)
Charlotte, NC 28202-1006

Richard L. Whitt, Esquire
Austin, Lewis & Rogers, P.A.
Post Office Box 11716
Columbia, SC 29211

Scott Elliott, Esquire
Elliott & Elliott, P.A.
721 Olive Street
Columbia, SC 29205

Pamela J. McMullan

July 31, 2006
Columbia, South Carolina

STUDY OF DUKE ENERGY CAROLINAS FUEL EXPENSES

DOCKET NO. 2005-3-E
(ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS)

OFFICE OF REGULATORY STAFF
ORS
SOUTH CAROLINA

Prepared by

THE OFFICE OF REGULATORY STAFF

ELECTRIC DEPARTMENT

July 31, 2006

(REDACTED VERSION)

STUDY OF DUKE ENERGY CAROLINAS FUEL EXPENSES

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STUDY OF DUKE ENERGY CAROLINAS FUEL EXPENSES

Background

Pursuant to an agreement among all parties regarding the *Annual Review of Base Rates for Fuel Costs of Duke Power Company (2005-3-E)*, the South Carolina Office of Regulatory Staff ("ORS") has performed a study of Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC ("DEC") fuel purchasing methods. The study generally encompasses the review period of January 2005 through December 2006. This study examines DEC's fuel-related activities and evaluates the reasonableness of its practices. Specifically, this study and analyses include the following subject matters with respect to fuel expenses: Fuel Procurement, Transportation of Fuel, Generation Planning, Fuel Mix, Purchased Power and Off-system Sales, Affiliate Transactions, Hedging Activities, Inventory Management, and ORS Site Visits.

DEC is a regulated public utility engaged in the generation, transmission, distribution, and sale of electricity to retail and wholesale customers in North Carolina and South Carolina. DEC is a subsidiary of Duke Energy Corporation. Duke Energy Corporation offers retail electric service to 3.7 million customers in the Carolinas, Kentucky, Indiana and Ohio and retail natural gas service to 500,000 customers in Kentucky, Indiana and Ohio. Its service area covers approximately 47,000 square miles in the Midwest and Southeast. Duke Energy Corporation's fleet of power plants include approximately 28,000 megawatts (MWs) of capacity. In North Carolina and South Carolina, its facilities serve approximately 2.2 million customers with a generating capability of approximately 19,900 MWs. Duke Energy Corporation maintains over $70 billion in assets and generates an annual revenue of approximately $27 billion. Its principal executive offices are located in Charlotte, North Carolina.

DEC operates a diverse mix of power generating units that include fossil, hydro, natural gas, fuel oil and nuclear. These units are geographically located throughout DEC's service territory in North Carolina and South Carolina (See Attachment A).

Fuel Procurement

Long-Term Contracts

Although DEC maintains significant nuclear generation resources, coal is also a major source of energy generation on DEC's system. During the review period, DEC received coal under 50 long-term contracts (See Attachment B). However, 17 of the long-term contracts expired in 2005 leaving 33 active contracts in 2006. The contracts generally range in term from [redacted]. However, DEC does maintain 2 long-term contracts with unique terms. [redacted]. However, this contract is based [redacted].

Also, [redacted] contract ([redacted]) has a term of [redacted]. This contract was negotiated and executed to allow delivery of make-up tons not received under the [redacted]. A new contract was required at a higher producer price since the undelivered tons were attributed to railroad non-performance and not supplier difficulties. Excluding contracts that expired in 2005, the annual tons secured by DEC's contracts range from [redacted] resulting in approximately [redacted] tons of long-term contract coal to be delivered annually. DEC may purchase coal with varying qualities but primarily procures coal based on the following specifications:

- Moisture: 7.0% (Maximum)
- Ash: 12.0% (Maximum)
- Sulfur: 2.15 lbs SO_2/MMBTU (Maximum)
- Volatile Matter: 30% (Minimum)
- Heat Value: 12,000 BTU/LB (Minimum)
- Ash Fusion (Reducing Atmosphere): 2,400 °F (Minimum)
- Hardgrove Grindability Index: 38 HGI (Minimum)
- Size: 2" x 0" (Maximum)

Attachment B also shows several contracts with a price increase during the term of the contract. When comparing the initial producer price to the current producer price, the most significant price increases were found in the [redacted]. The price increases were [redacted], respectively.

The [redacted] contract reflects contract negotiations in 2005 which extended the contract through December 2006. The initial contract price of [redacted] was less than the corresponding spot market price of [redacted][1] at the time the contract was executed in July 2002. The current producer price of [redacted] is based on a weighted average of [redacted] at [redacted] to be delivered in 2005 and [redacted] to be delivered in 2006. At the time of the contract negotiations in 2005, the [redacted] and the [redacted] were below the average weekly spot market price of $63.21/ton in 2005.[2]

The [redacted] contract also reflects contract negotiations in 2005 which extended the contract through December 2006. The initial contract price of [redacted] was less than the corresponding spot market price of $39.00/ton at the time the contract was executed in January 2004. The current producer price of [redacted] was also below the average weekly spot market price of $63.21/ton in 2005.

Very similar to the [redacted] contract, the [redacted] contract, again, reflects contract negotiations in 2005 which extended the contract through December 2006. The initial contract price of [redacted] was below the corresponding spot market price of $39.00/ton at the time

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[1] *See Attachment C for corresponding spot market prices*
[2] *Energy Information Administration; Central Appalachia Coal (12,500 Btu/lb, 1.2 lbs SO_2/MMBTU)*

the contract was executed in January 2004. The current producer price of [redacted] (low BTU coal) was below the average weekly spot market price of $63.21/ton in 2005.

The [redacted] initial contract price of [redacted] was less than the corresponding spot market price of $31.10/ton at the time the contract was executed in January 2003. The contract includes negotiated fixed price increases during the term of the contract. The prices were: January 1, 2003 - December 31, 2003: [redacted]; January 1, 2004 - December 31, 2004: [redacted]; January 1, 2005 - June 30, 2005: [redacted]. The contract was extended from July 1, 2005 to December 31, 2005 at [redacted]. This price was below the average weekly spot market price of $63.21/ton in 2005. Excluding the [redacted] contract which expired on December 31, 2005, the above remaining 3 effective contracts additively supply [redacted] annual tons or approximately [redacted] of DEC's long-term contract purchases.

DEC's coal purchases originate primarily within the Central Appalachia Coal Region (Eastern Kentucky, Western Virginia, Eastern Tennessee, and West Virginia). DEC maintains a transportation contract with the Norfolk Southern Railroad Company ("NS") and the CSX Transportation Company ("CSX"). Sixteen of the 33 active long-term contracts exclusively utilize the [redacted] railroad system. DEC also maintains 17 long-term producer contracts that exclusively utilize the [redacted] railroad system. Also, although the Marshall Steam Station has duel railroad access, only [redacted] is currently contracted to deliver coal to the Marshall plant.

For the active long-term contracts, the [redacted] has transportation costs of [redacted], [redacted]; and, the [redacted] has transportation costs of [redacted], [redacted]. The [redacted] contract reflects a delivered cost of [redacted] which represents DEC's most expensive coal purchase price. DEC secured [redacted] annual tons through the [redacted] contract which represents approximately [redacted] of DEC's long-term contract purchases.

ORS compared each long-term initial contract price to the corresponding actual Energy Information Administration average weekly spot market price at the time the contract was let (See Attachment C). This approach allowed ORS to evaluate DEC's success in negotiating advantageous terms for its long-term coal contracts. Of the 50 long-term contracts, only the [redacted] contract reflects a coal price higher than the corresponding spot market price. The initial contract price of [redacted] was 0.75% above the corresponding spot market price at the time the contract was let. The contract negotiations secured a fixed price of [redacted] and approximately [redacted] to be delivered during the contract's [redacted]. DEC reports to ORS that the fixed price and quantity insulated DEC from escalating fuel costs. When the contract expired in 2005, the fixed contract price of [redacted] was below the average weekly spot market price of $63.21/ton in 2005.

Short-Term Spot Contracts

ORS evaluated DEC's short-term contracts which supplement its existing long-term contracts, for inventory management and to take advantage of market conditions (See Attachment D). DEC secured 58 spot contracts in 2005 and had secured 12 contracts for 2006 at the time of this study. The contracts vary in term ranging from 1 month to 11 months. The quantity secured by the 2005 and 2006 spot contracts range from [redacted] [redacted]. DEC's spot contracts secured approximately [redacted] of coal for 2005. The physical properties of the spot coal meet the same standard specifications as for the long-term contracts, described above.

As with its long-term contracts, DEC transports its spot coal via the NS and CSX railroad systems primarily from the Central Appalachia Coal Region. Twenty-five of the 70 short-term contracts exclusively utilize the [redacted] railroad system. Forty-five of the short-term contracts exclusively utilize the [redacted] railroad system.

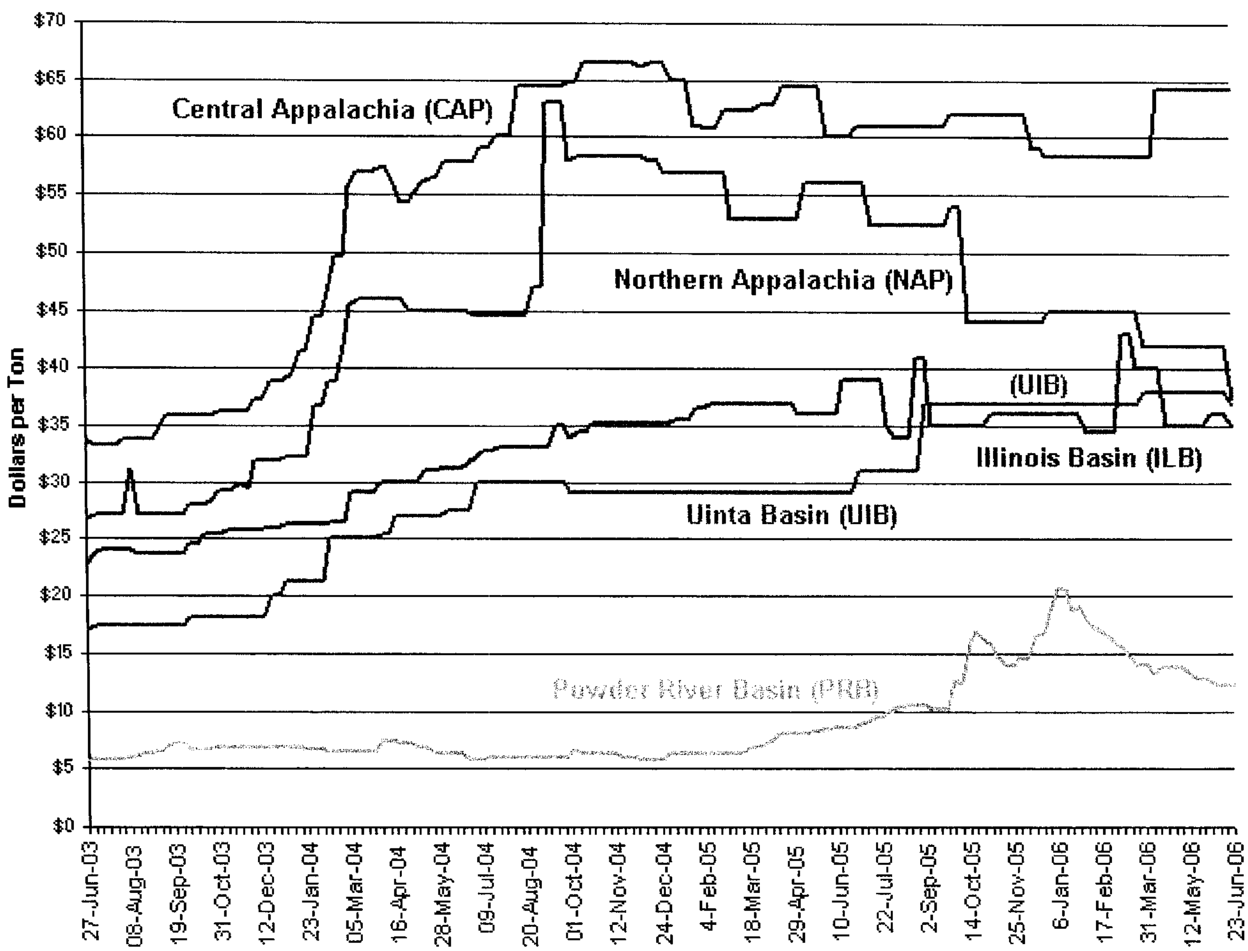
The NS railroad system has transportation costs of [redacted] and [redacted]. The [redacted] reflects the total transportation cost from the Powder River Basin (PRB) in Wyoming to the Buck Steam Station. The coal was delivered via the Burlington Northern Railroad to Memphis, TN and interchanged to the NS system for ultimate delivery at the Buck Steam Station. This purchase allowed DEC to test PRB coal quality, handling, and performance at the Buck plant. The [redacted] railroad system has transportation costs of [redacted] and [redacted]. The [redacted] coal purchase is the most expensive purchase at a delivered cost of [redacted]. This contract secured compliance coal consisting of an extremely low sulfur content of 0.50%. DEC purchased this coal to perform test burns at its Belews Creek Steam Station as well as meet its 2006 tonnage requirements. DEC secured [redacted] tons through this off-shore spot contract. With reference to 2005 purchased tonnage, this 2006 contract would equate to approximately [redacted] of DEC's short-term contract purchases.

ORS compared each spot contract price to the corresponding actual spot market price at the time the contract was let (See Attachment E). This approach allowed ORS to evaluate DEC's success in negotiating advantageous terms for its short-term coal contracts. Of the 70 spot contracts, only the [redacted] contract reflects a coal price higher than the corresponding spot market price for coal at the time the contract was let. DEC purchased this coal to meet its 2006 tonnage requirements. DEC secured [redacted] through this domestic coal contract.

With reference to 2005 purchased tonnage, this 2006 contract would equate to less than [redacted] of DEC's short-term contract purchases.

Lastly, it should be noted that during the review period, coal prices experienced unprecedented increases. Graph 1 below illustrates the increasing price for coal by geographic region over the 3 year period ending June 2006.

Graph 1: Coal Commodities by Region



Key to Coal Commodities by Region[1]

Central Appalachia:	Big Sandy/Kanawha 12,500 Btu, 1.2 lbSO2/mmBtu	Powder River Basin:	8,800 Btu, 0.8 lb SO2/mmBtu
Northern Appalachia:	Pittsburgh Seam 13,000 Btu, <3.0 lbSO2/mmBtu	Uinta Basin in Colo.:	11,700 Btu, 0.8 lb SO2/mmBtu
Illinois Basin:	11,800 Btu, 5.0 lb SO2/mmBtu		

Source: Energy Information Administration - US Department of Energy (6.23.06)

Coal Procurement Process

ORS reviewed DEC's [redacted] document. This written policy applies directly to DEC's Procurement, Coal and Bulk Material Department. The following are the six major components of this document as it relates to coal procurement:

(1) Consumption Requirements

(2) Inventory Requirements

(3) Procurement Planning and Strategy Development

(4) Bid Solicitation and Supplier Selection

(5) Contract Development

(6) Contract Compliance

This DEC policy supports Duke Energy Corporation's [redacted] which establishes minimum controls required for purchases for its business/corporate units. This Duke Energy Corporation policy also defines employee roles and responsibilities as well as establishes approval levels for purchases.

Based on inventory status and contract expiration dates, DEC periodically issues solicitations to secure long-term contracts and/or spot purchases to manage inventory levels. DEC evaluates the bids received from approved suppliers in accordance with the above policies. The solicited bid proposals are evaluated and approved based on a number of factors to include but not limited to: price (including transportation charges), condition of pricing (firm, escalated, etc.), fuel quality and quantity, conformance with bid specifications and guidelines, exceptions to the bid specifications and guidelines, supplier capability/reliability, supplier's financial condition including a credit risk analysis, supplier operation and/or transportation sourcing, and current market conditions. The above evaluation process generates a short-list of potential suppliers from which one or more contracts are executed.

Natural Gas Procurement Process

Although DEC maintains approximately 2,500 MWs of natural gas-fired (and/or fuel oil) generation (See Generation Planning Section), DEC is a very small consumer of natural gas. For the twelve months ended June 30, 2005, DEC's natural gas-fired generation contributed 0% to its fuel mix (See Fuel Mix Section). Therefore, this fuel study does not evaluate DEC's natural gas procurement process in depth, due to DEC's limited activity in the natural gas market.

In summary, during the review period, the entire industry as well as DEC faced significant price increases due to the upward market trend for coal. To secure coal contracts with advantageous pricing terms, not withstanding unfavorable market conditions, DEC should continue to work diligently and ensure its long-term and short-term purchases for coal are at or below the corresponding market value.

Transportation of Fuel

As mentioned above in the Fuel Procurement Section, DEC utilizes the NS and CSX railroad systems to transport coal to its power generating facilities. Excluding contracts that expired in 2005, DEC transported approximately [redacted] (or [redacted]) of its long-term coal contract purchases via the [redacted] railroad system. Conversely, DEC transported approximately [redacted] (or [redacted]) of its long-term coal contract purchases via the [redacted] railroad system. DEC maintains one transportation contract with each railroad company (See Table 1). As mentioned earlier, the Marshall Steam Station has duel railroad access; however, only [redacted] is currently contracted to deliver coal to the Marshall plant. Also, DEC does not utilize private rail cars.

Table 1: Railroad Transportation Contracts

Transporter	Contract #	Term	Plant
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

DEC's NS transportation contract contains base rates subject to a [redacted].

DEC's CSX transportation contract contains base rates that are subject to [redacted].

To evaluate delivery performance, ORS reviewed DEC's ability to consistently receive coal in accordance with its transportation contracts. DEC's levelized, ratable monthly delivery volume based upon projected annual fuel burn for plants served by the [redacted] for 2005 was [redacted] This amount does not represent the actual scheduled deliveries in 2005. Graph 2 illustrates actual deliveries by [redacted] in 2005 as compared to this levelized, ratable monthly volume. Similarly, DEC's levelized, ratable monthly delivery volume based upon projected annual fuel burn for plants served by the [redacted] for 2005 was [redacted] Graph 3 illustrates actual deliveries by [redacted] in 2005 as compared to this levelized, ratable monthly volume.

[redacted]

[redacted]

[redacted]

The resulting cumulative effect of actual delivery performance for 2005 was approximately [redacted]. Based on the combined delivery performance of both railroad companies, the overall cumulative effect to DEC's system [redacted]. However, it should be noted that delivery short-fall, in any given month, may not be entirely attributed to railroad performance. Supplier difficulties as well as failure of a utility's coal handling facilities may also adversely impact delivery success.

ORS performed a historical review of utility coal costs for the period of April 2004 through June 2005 (See Tables 2, 3, and 4). A review of transportation costs revealed that DEC had the highest average freight cost of $16.82/ton. DEC's transportation costs closely coincided with that of Progress Energy Carolinas when compared to the other major investor-owned utilities operating in South Carolina. The tables below show Progress Energy Carolinas had a 1.3% lower transportation cost, and South Carolina Electric & Gas Company had a 22.5% lower average transportation cost.

Table 2: Duke Energy Carolinas

Month	Invoice Cost per Ton	Freight Cost per Ton	Total Cost per Ton	Cost per MMBTU	Btu of Coal
	$	$	$	$	Btu/lb
Apr-04	32.18	15.41	47.59	1.9331	12,309
May-04	32.46	15.55	48.01	1.9591	12,253
Jun-04	32.05	16.54	48.59	1.9922	12,195
Jul-04	33.40	16.80	50.20	2.0517	12,234
Aug-04	34.25	16.52	50.77	2.0639	12,300
Sep-04	33.74	16.76	50.50	2.0631	12,239
Oct-04	32.17	16.54	48.71	1.9980	12,190
Nov-04	35.08	14.56	49.64	2.0264	12,248
Dec-04	33.79	17.42	51.21	2.1058	12,159
Jan-05	35.89	16.92	52.81	2.1615	12,216
Feb-05	37.66	16.29	53.95	2.1993	12,265
Mar-05	37.21	17.98	55.19	2.2537	12,244
Apr-05	37.29	18.69	55.98	2.2454	12,466
May-05	37.80	17.63	55.43	2.2832	12,138
Jun-05	40.33	18.62	58.95	2.3457	12,566
Average	**35.02**	**16.82**	**51.84**	**2.1121**	**12,268**

Table 3: Progress Energy Carolinas

Month	Invoice Cost per Ton	Freight Cost per Ton	Total Cost per Ton	Cost per MMBTU	Btu of Coal
	$	$	$	$	Btu/lb
Apr-04	36.42	14.61	51.03	2.0560	12,410
May-04	35.64	15.04	50.68	2.0446	12,394
Jun-04	38.54	14.54	53.08	2.1495	12,347
Jul-04	44.20	13.78	57.98	2.3376	12,402
Aug-04	43.73	13.92	57.65	2.3394	12,322
Sep-04	41.06	14.03	55.09	2.2249	12,380
Oct-04	38.67	15.17	53.84	2.1706	12,402
Nov-04	41.14	14.84	55.98	2.2514	12,432
Dec-04	46.81	18.15	64.96	2.6387	12,309
Jan-05	44.38	18.58	62.96	2.5318	12,434
Feb-05	44.43	18.30	62.73	2.5100	12,496
Mar-05	47.05	17.69	64.74	2.5980	12,460
Apr-05	48.03	19.16	67.19	2.6927	12,476
May-05	47.41	19.65	67.06	2.7308	12,278
Jun-05	49.55	21.50	71.05	2.8719	12,370
Average	**43.14**	**16.60**	**59.73**	**2.4099**	**12,394**

Table 4: South Carolina Electric & Gas Company

Month	Invoice cost per Ton	Freight Cost per Ton	Total Cost per Ton	Cost per MMBTU	Btu of Coal
	$	$	$	$	Btu/lb
Apr-04	37.53	13.40	50.93	2.0176	12,621
May-04	37.52	12.07	49.59	1.9566	12,672
Jun-04	39.53	12.92	52.45	2.0821	12,595
Jul-04	35.93	12.61	48.54	1.9187	12,649
Aug-04	41.14	11.26	52.40	2.0844	12,570
Sep-04	38.07	14.20	52.27	2.0901	12,504
Oct-04	37.82	13.17	50.99	2.0357	12,524
Nov-04	43.54	11.34	54.88	2.1668	12,664
Dec-04	37.47	12.94	50.41	2.0026	12,586
Jan-05	49.94	10.74	60.68	2.3853	12,720
Feb-05	43.17	15.49	58.66	2.3205	12,640
Mar-05	48.62	12.41	61.03	2.4081	12,672
Apr-05	47.06	13.81	60.87	2.4112	12,622
May-05	44.95	13.85	58.80	2.3278	12,630
Jun-05	46.56	15.36	61.92	2.4429	12,673
Average	**41.92**	**13.04**	**54.96**	**2.1767**	**12,623**

To better evaluate the impact on the ratepayer, it is important to compare the relative average cost per ton of delivered coal by utility. They are $51.84/ton, $59.73/ton and $54.96/ton for DEC, Progress Energy Carolinas, and South Carolina Electric & Gas Company, respectively. That is, although DEC had a higher average transportation cost, it had a lesser impact on the ratepayer due to its lower delivered cost of coal. This finding can be primarily attributed to DEC's lower invoice cost.

To compare the major investor owned utilities, ORS performed a historical review of coal costs by reviewing producer cost, freight cost, and delivered cost. Graph 5 of Attachment F shows a correlation between the major utilities with regard to producer cost. This graph demonstrates that there has been a similar market for coal available to each utility over the past several years. However, DEC appears to have had an advantage on producer cost for coal since late 2001.

Graph 6 of Attachment G shows that DEC and Progress Energy Carolinas have had very similar historical freight costs. Graph 6 also shows that DEC and Progress Energy Carolinas experienced a significant increase in freight cost in the first quarter of 2002. The increase for

DEC is attributable to expiring contracts and a transition to the [redacted] and [redacted] tariff (maximum) rates during the period in which DEC pursued rate relief before the Surface Transportation Board. The proceedings were ultimately settled resulting in new multi-year transportation contracts consistent with the tariff rates. Consequently, since 2002, South Carolina Electric & Gas Company has had an overall advantage in freight costs.

Graph 7 of Attachment H shows a close correlation and upward trend with regard to the delivered cost of coal for each major utility. Graph 8 of Attachment I shows the relative comparison of the BTU content of coal purchased by each major utility. Also, Graph 8 illustrates that South Carolina Electric & Gas Company has historically purchased coal with a higher BTU content.

In summary, DEC should evaluate the potential benefits of utilizing private rail cars. If appropriate, DEC should incorporate provisions into its contracts with NS and CSX to allow use of private rail cars. Also, due to the noteworthy cumulative delta for CSX, DEC should evaluate and explore all available and applicable remedies against CSX for failure to perform and determine the reasonableness of pursuing such remedies. In addition, when contract renewals occur, DEC should attempt to have its contracts with NS, CSX and DEC's suppliers structured to encourage more timely supply and delivery and should strive to incorporate into its contracts appropriate remedies when the contract terms are not met. Lastly, DEC should also evaluate any and all cost effective alternatives to ensure adequate supply, inventory, and delivery.

Generation Planning

ORS reviewed DEC's *November 2005 Annual Plan* ("Annual Plan") which includes DEC's integrated resource planning process. The Annual Plan provides an evaluation of DEC's future generation needs through 2020. DEC's 2006 forecasted summer peak and winter peak loads are 17,376 MWs and 15,425 MWs, respectively. DEC forecasts a 32% increase in the summer peak load and a 19% increase in the winter peak load over the 15 year period. With these increases, the total annual energy sales are predicted to be 119,707 GWH in 2020.

The Annual Plan evaluates DEC's current resource mix which includes a diverse mix of generation as well as Demand Side Management resources:

- Nuclear Capacity (base) - 6,996 MWs
- Coal Capacity (baseload/intermediate) - 7,754 MWs
- Combustion Turbines (peaking) - 2,447 MWs
- Hydro and Pumped Storage (load following/peaking) - 3,169 MWs
- Purchased Power Contracts - 618 MWs
- Demand Side Management Programs (customer load reductions) - 766 MWs

DEC's load forecast incorporates a planning process that evaluates viable future resource options to include: purchased power agreements, generation capacity up-rates, new DEC-owned generation, and customer demand side options. The resource selection is based on future summer and winter peak load-shape needs to complement DEC's existing generation portfolio, lowest cost energy, and regulatory requirements.

The Annual Plan incorporates a 17% target reserve margin over a 15 year horizon to help ensure the availability of adequate resources to meet customer demands in response to unanticipated weather extremes, load growth, and generation outages. DEC uses this target to maintain operating reserves and contingency reserves as established by the North American Electric Reliability Council (NERC) Reliability Standards.

The Annual Plan shows that DEC has sufficient resources to meet customer demand through 2006. However, DEC will need an additional 350 MWs in early 2007 and up to 1,500 MWs for 2009. Accordingly, DEC has secured three capacity contracts with Progress Ventures, Inc. to provide approximately 460 MWs between 2006 and 2008. Also, DEC secured one capacity contract with Dynegy Power Marketing, Inc. to provide 160 MWs which became effective on January 1, 2006. Collectively, these contracts supply approximately 620 MWs of additional capacity to DEC's portfolio. Also, DEC is currently in the process of completing the transaction to acquire the entire (825 MWs) Rockingham Generating Facility from Dynegy. These firm contracts and plant acquisitions will satisfy DEC's immediate and near future demand needs. DEC is also evaluating a combination of additional baseload, intermediate, peaking and DSM programs to address customer demand over the next 15 years. According to the 2005 Annual Plan, the most favorable option is to install 1,600 MWs of new coal capacity by 2011 and 2,200 MWs of nuclear capacity by 2016. DEC has already taken preliminary steps toward this goal. DEC's Annual Plan appears reasonable in addressing future system needs.

Fuel Mix

Table 5, below, demonstrates the effect on a utility's overall fuel expense due to generation mix from the rate based plants and from purchased power of each utility. Table 5 utilizes the percentage generation by fuel and supply source for both South Carolina Electric & Gas Company and DEC for the twelve months ended June 30, 2005, and for Progress Energy Carolinas for the year ended February 2006, along with a predetermined cost per kilowatt-hour for each type of fuel source and purchased power regardless of company plant affiliation. The fuel categories and associated costs used are Nuclear (0.5 cents/kwh), Coal (2.75 cents/kwh), Natural Gas/Oil (10.0 cents/kwh), Hydro (0.0 cents/kwh), and Purchased Power (3.6 cents/kwh). The predetermined costs are approximations for these fuel cost categories utilizing recent costs, representative of these three utilities. The total or overall cost for each utility is weighted for each fuel source and purchased power expense by multiplying each category cost by the percentage of generation produced or provided from that source. The individual weighted costs are then combined to show the resulting overall average fuel expense that would be expected for a company with that corresponding generation mix. Hydro generation is included at zero fuel cost to account for not only run-of-river type production with zero actual fuel costs, but also to weight the overall generation from pumped storage facilities where the pump-up costs are reflected in other type generation fuel costs.

The intent of Table 5 is to show how rate based generating facilities along with purchased power impact fuel costs. The companies' rate based plants have gone through certification processes as well as prudency reviews, and each utility's facilities have been formally determined to be appropriate for each respective system.

Table 5: Projected Fuel Cost Based on Generation Mix by Fuel Type and Purchased Power

	SCE&G	Wtd (¢/kwh)	DEC	Wtd (¢/kwh)	Progress	Wtd (¢/kwh)
Nuclear (0.5 ¢/kwh)	19.0%	0.10	47.0%	0.24	39.5%	0.20
Coal (2.75 ¢/kwh)	68.0%	1.87	50.9%	1.40	48.3%	1.33
Natural Gas/Oil (10.0 ¢/kwh)	6.3%	0.63	0.0%	0.00	3.6%	0.36
Hydro (0.0 ¢/kwh)	4.7%	0.00	1.6%	0.00	1.2%	0.00
Purchased Power (3.6 ¢/kwh)	2.0%	0.07	0.5%	0.02	7.4%	0.26
Total (%)	**100.0%**		**100.0%**		**100.0%**	
Total Weighted (¢/kwh)		**2.67**		**1.66**		**2.15**

Setting identical predetermined costs for all three utilities equates to the assumption that each utility's fuel purchase costs are the same. The resulting diverse total costs for the three utilities demonstrates the significant effect that kilowatt-hour generation and supply mix has on a utility's bottom line fuel expenses. The difference between the lowest (1.66 cents/kwh for DEC) and highest (2.67 cents/kwh for SCE&G) total fuel costs is approximately sixty (60%) percent, although the cost for the respective fuels is the same for each company.

Even with the assumption for all three utilities that all plant operations, purchased power and fuel costs are reasonable, Table 5 demonstrates that there are logical and legitimate reasons and circumstances for one utility's fuel costs exceeding those of another based on generation and supply mix diversity. Table 5 can be a useful tool in analyzing and explaining the varying fuel expenses among utilities in a more simplistic manner considering the complexity of the fuel procurement process and the operations of diverse generation facilities and systems.

Purchased Power and Off-system Sales

DEC has entered into firm contracts for purchased power with 2 electric suppliers. They are with Progress Ventures, Inc. and Dynegy Power Marketing, Inc. DEC secured 3 separate contracts with Progress Ventures, Inc. for firm purchases of power via generating units located in Rowan County, N.C. The Rowan units are natural gas-fired simple cycle combustion turbines. The contract for Rowan Unit 1 provides 152 MWs for the contract term of June 1, 2002 through May 31, 2007. This contract will automatically renew upon its expiration and will continue from June 1, 2007 through December 31, 2010. The contract for Rowan Unit 2 provides 153 MWs for the contract term of January 1, 2006 through December 31, 2010. The contract for Rowan Unit 3 provides 153 MWs for the contract term of June 1, 2004 through May 31, 2008. This contract will automatically renew upon its expiration and will continue from June 1, 2008 through December 31, 2010.

The [redacted] contract provides 160 MWs of capacity from Rockingham Power, LLC for the contract term of January 1, 2006 through December 31, 2010. The Rockingham unit is a natural gas-fired simple cycle combustion turbine located in Rockingham County, N.C. As mentioned above in the Generation Planning Section, DEC is currently in the process of completing the transaction to acquire the Rockingham Generating Facility from [redacted]. The firm contract with [redacted] will terminate once the transaction to acquire the Rockingham facility is completed.

DEC uses the avoided cost method to determine the fuel component of purchases of power for DEC's retail native load customers. Under this methodology, DEC determines the costs it would have incurred in the absence of the purchase. This cost is determined by use of a model that identifies the incremental cost of the unit that would have been dispatched in the absence of the purchase and compares that cost to the cost of the purchase. The incremental cost includes the fuel and certain variable operation and maintenance costs. DEC includes in fuel costs the lower of the cost DEC would have incurred, or the cost of the energy purchase. Fuel from purchases of power to supply off-system sales is subtracted from the fuel expense for the applicable period before calculating fuel costs in support of retail native load. DEC is adhering to its internal practices to ensure the least cost energy is dedicated to the retail native load.

Affiliate Transactions

During the calendar years 2004 and 2005, DEC did not purchase any fuel resources or transportation services from an affiliate. However, in 2005, DEC received four mixed plutonium oxide and uranium oxide ("MOX") fuel assemblies from its affiliate Duke COGEMA Stone & Webster, LLC ("DCS") pursuant to a Lead Test Assembly ("LTA") Fuel Fabrication Contract between DEC and DCS. Under this contract, DCS supplied the LTAs to DEC at no charge in order for DEC to use the fuel and perform evaluations and analyses necessary to obtain

Nuclear Regulatory Commission approval for batch use of MOX fuel. The four LTAs were loaded into Catawba Unit 1 during 2005. Also, DCS is the primary contractor for the U.S. Department of Energy's MOX fuel programs. DCS and DEC entered into a sub-contract which provides for DEC to prepare the McGuire and Catawba nuclear reactors for use of MOX fuel and evaluates the purchase of MOX fuel for use in the reactors.

On February 22, 2006, Duke Capital LLC, a direct wholly-owned subsidiary of Duke Energy Corporation, sold all of the capital stock of Duke Project Services Group, which manages the MOX program for DEC, to Shaw Environmental & Infrastructure, Inc. Therefore, as of February 22, 2006, DEC ceased to be an affiliate of Duke Project Services Group as well as DCS.

Hedging Activities

DEC currently does not employ any financial hedging activities for coal purchases. DEC utilizes staggered contract expiration dates to provide insulation from market volatility while ensuring a continuous supply of coal.

Also, DEC does not employ any financial hedging for natural gas purchases. As mentioned above in the Natural Gas Procurement Process Sub-section, DEC consumes a very small quantity of natural gas. However, DEC should monitor and evaluate possible cost effective financial hedging opportunities for coal as well as natural gas to further mitigate market volatility.

Inventory Management

ORS reviewed DEC's inventory control process (See Attachment J). DEC's average monthly inventory for 2005 was approximately [redacted] tons. DEC forecasts an average monthly inventory for 2006 of approximately [redacted] tons for its system. DEC purchases coal to sustain its inventory on a "target" system basis. DEC utilizes the Utility Fuel Inventory Model

("UFIM") and internal evaluations to establish average annual inventory targets. Inventory levels are monitored and managed based on the "ComTrac" computer modeling results. The inventory targets are based on a monthly target of [redacted] based on a system-wide full load burn (FLB) rate.

Table 6 below presents a summary of DEC's inventory level from January through December 2005. Target inventory is compared to actual inventory based on a system-wide FLB rate. A review of Table 6 shows that DEC frequently fell short of its inventory targets in 2005. DEC should continue to work toward rebuilding depleted inventories realized in 2005 and achieving its target in 2006.

Table 6: DEC Inventory Target Summary (2005)

Month	Target Days @ FLB	Actual Days @ FLB
January	[redacted]	[redacted]
February	[redacted]	[redacted]
March	[redacted]	[redacted]
April	[redacted]	[redacted]
May	[redacted]	[redacted]
June	[redacted]	[redacted]
July	[redacted]	[redacted]
August	[redacted]	[redacted]
September	[redacted]	[redacted]
October	[redacted]	[redacted]
November	[redacted]	[redacted]
December	[redacted]	[redacted]

ORS Site Visits

ORS met with DEC representatives to discuss DEC's fuel procurement practices. These meetings occurred at ORS as well as DEC's headquarters in Charlotte, N.C. ORS visited the Catawba Nuclear Station in York County, S.C. and the Lee Steam Station in Anderson County, S.C. to physically observe the electricity generation process at nuclear and fossil fuel power plants. Also, ORS visited DEC's purchase power operations and DEC's unit dispatching operations in Charlotte, N.C. In July 2005, ORS also toured the mining operations and coal loading system (tipple) in Pikeville and Hazard, Kentucky. During the visit, ORS toured TECO's surface and underground mining activities as well as its coal laboratories dedicated to sampling and determining coal qualities.

Recommendations

ORS offers the following suggestions and/or recommendations to enhance DEC's fuel management activities:

I. DEC should only consider purchasing coal from more expensive domestic or off-shore markets as a last alternative in acquiring fuel.

II. DEC should evaluate the potential benefits of utilizing private rail cars. If appropriate, DEC should incorporate provisions into its contracts with NS and CSX to allow use of private rail cars.

III. DEC should evaluate and explore all available and applicable remedies against NS, CSX and its suppliers for failure to perform and determine the reasonableness of pursuing such remedies.

IV. DEC should attempt to have its contracts with NS, CSX and DEC's suppliers structured to encourage more timely supply and delivery and should strive to incorporate into its contracts appropriate remedies when the contract terms are not met.

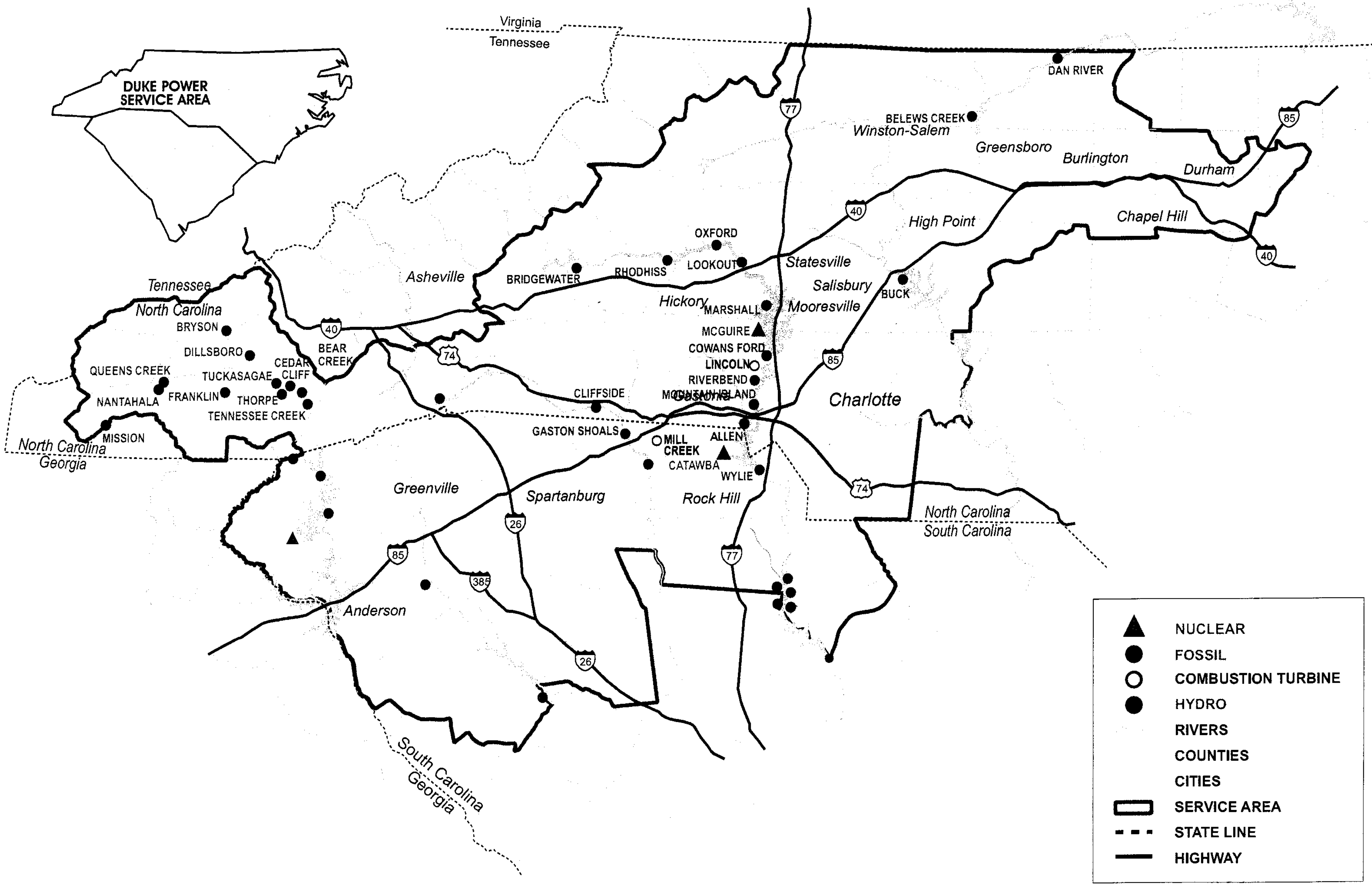
V. DEC should evaluate possible advantageous hedging opportunities to mitigate market volatility for coal as well as natural gas.

VI. DEC should work toward rebuilding depleted inventories realized in 2005 and achieving its target in 2006.

VII. In accordance with state statute, ORS request and/or Commission Order, DEC should file or continue to file with ORS the following information:

- Annual updated fuel forecast
- Monthly Over/Under Cumulative Recovery Report
- Notice of significant cumulative recovery trends
- Notice of significant fuel cost trends
- Monthly FERC Form 423
- Any industry solicitation for coal

ATTACHMENT A



DP_ElectricOperations
3/31/06

ATTACHMENT B

DUKE ENERGY CAROLINAS FUEL STUDY
PRODUCER LONG-TERM CONTRACTS (GREATER THAN ONE YEAR)

REDACTED

ATTACHMENT C

DUKE ENERGY CAROLINAS FUEL STUDY
LONG-TERM CONTRACT AND SPOT MARKET PRICE COMPARISON
(CONFIDENTIAL)

REDACTED

ATTACHMENT D

Duke Energy Carolinas Fuel Study
PRODUCER SHORT-TERM CONTRACTS (LESS THAN ONE YEAR)

REDACTED

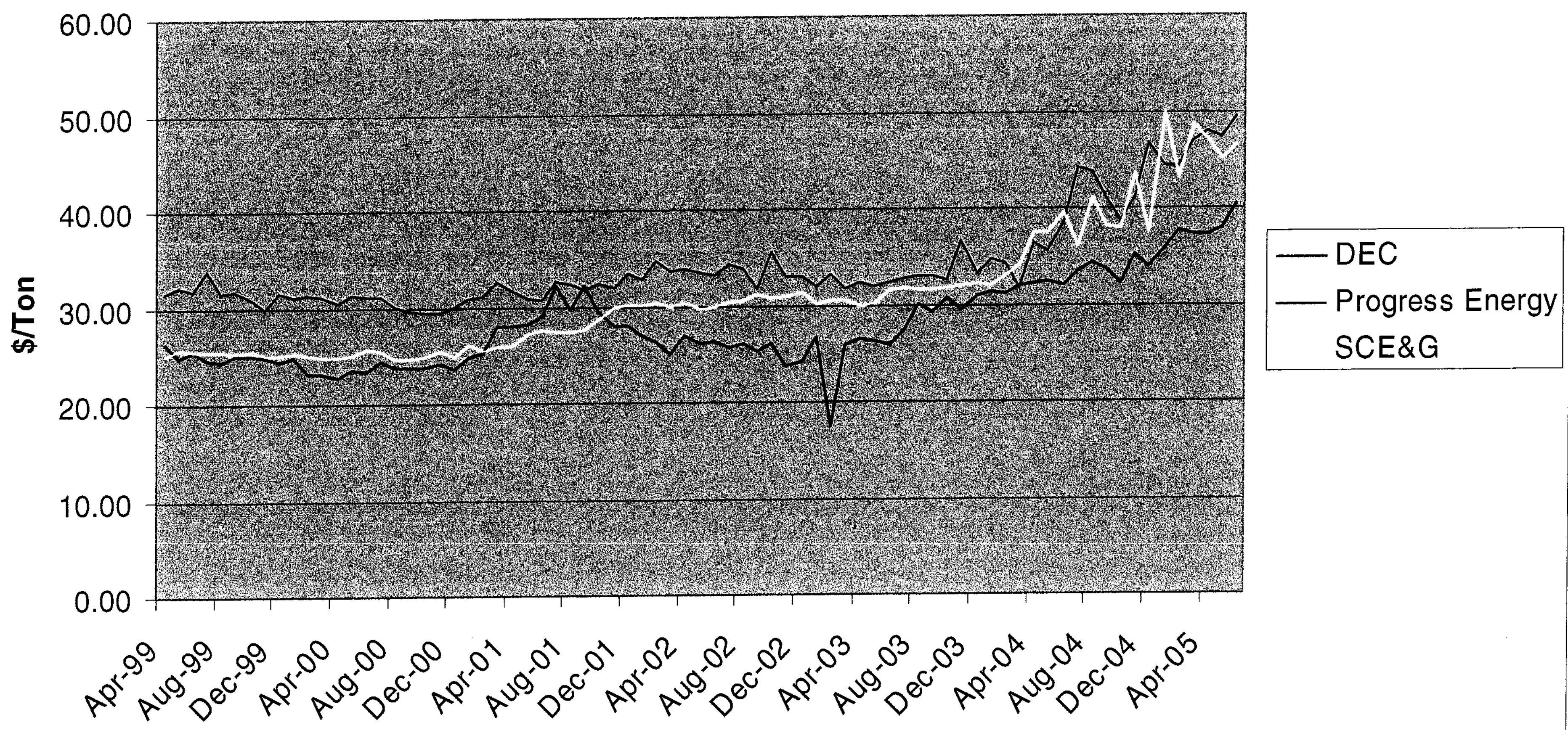
ATTACHMENT E

Duke Energy Carolinas Fuel Study
SHORT-TERM CONTRACT AND SPOT MARKET PRICE COMPARISON
(CONFIDENTIAL)

REDACTED

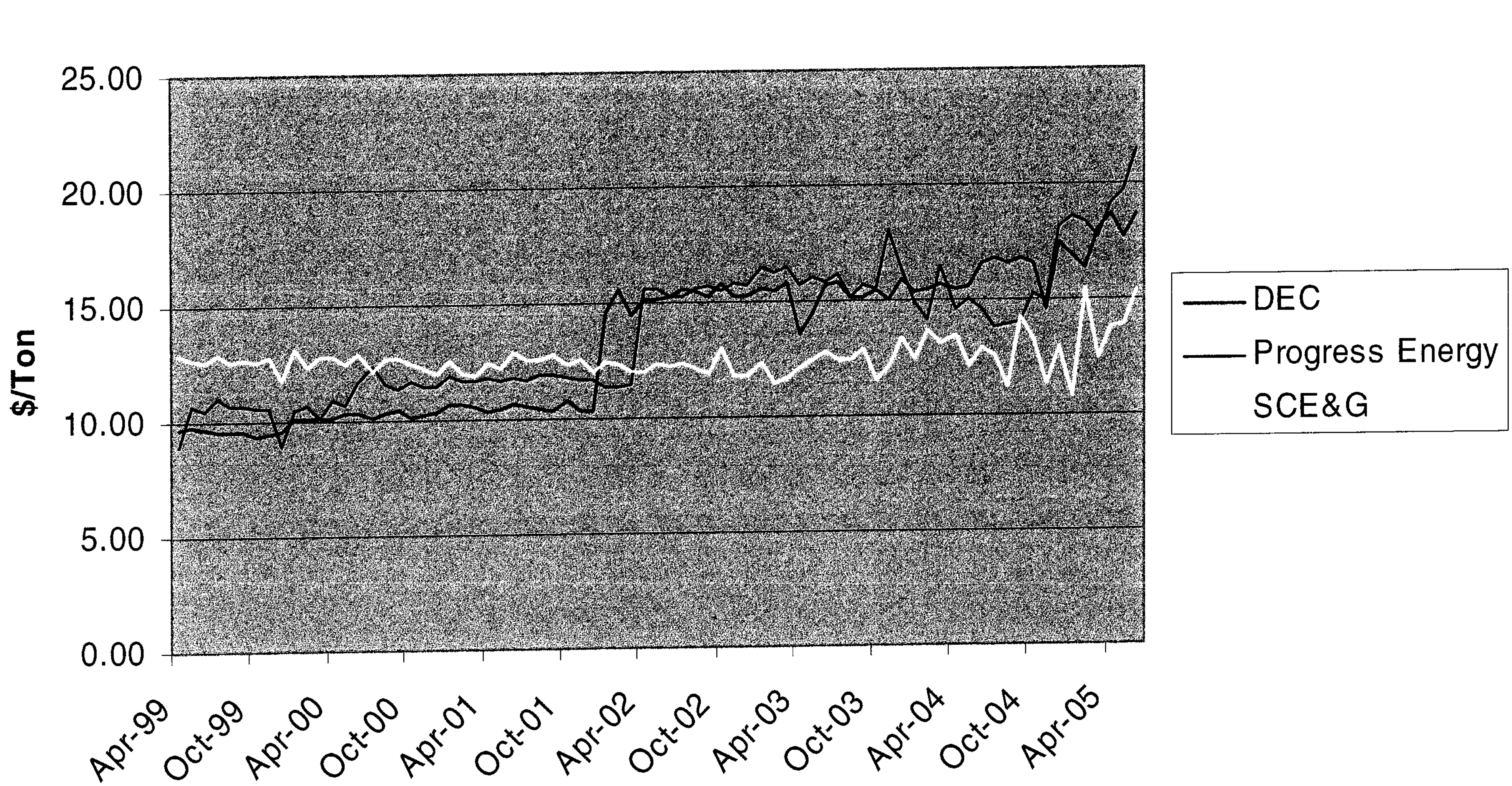
ATTACHMENT F

Graph 5 - Producer Cost (4/99 - 6/05)



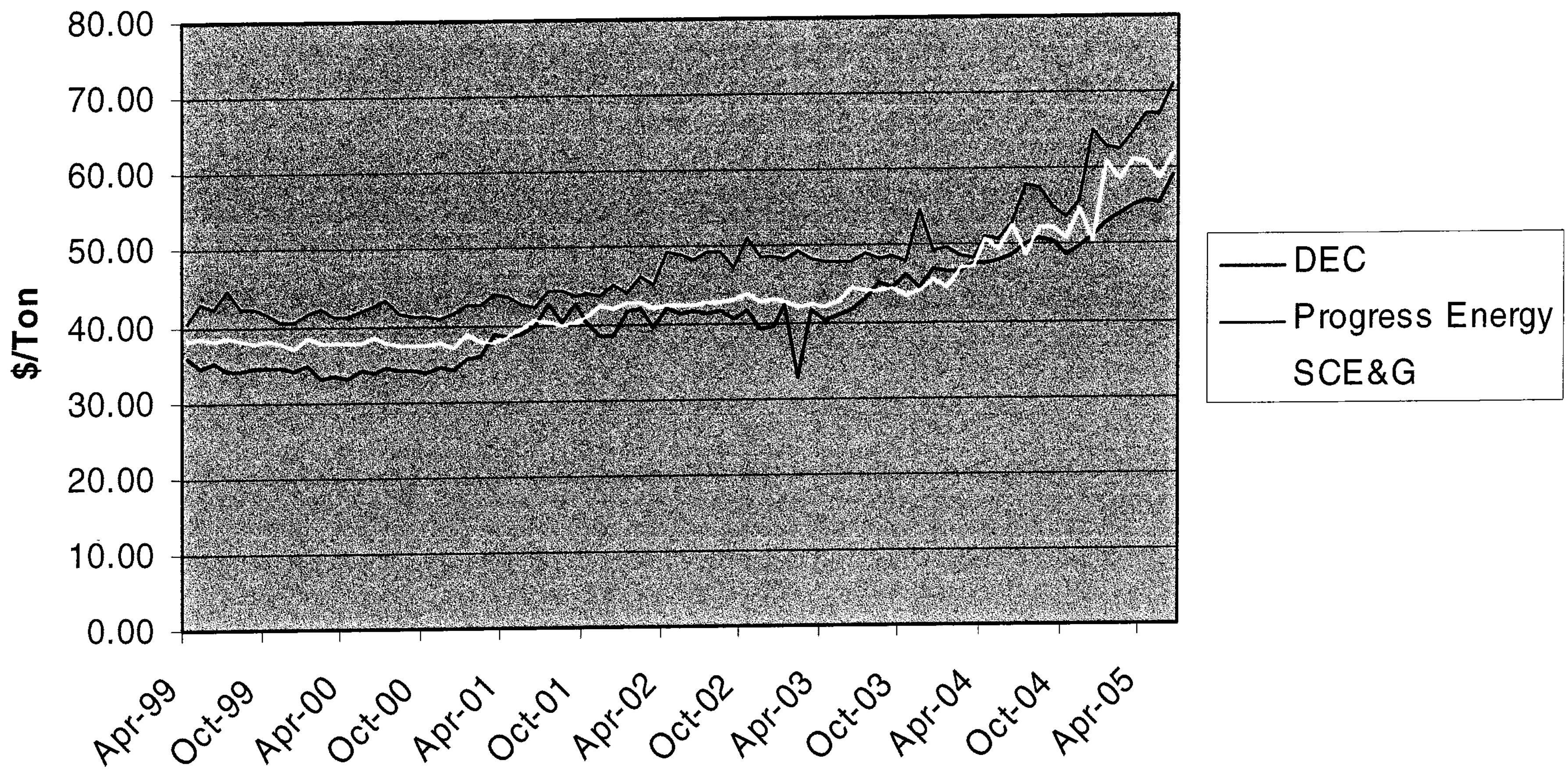
ATTACHMENT G

Graph 6 - Freight Cost (4/99 - 6/05)



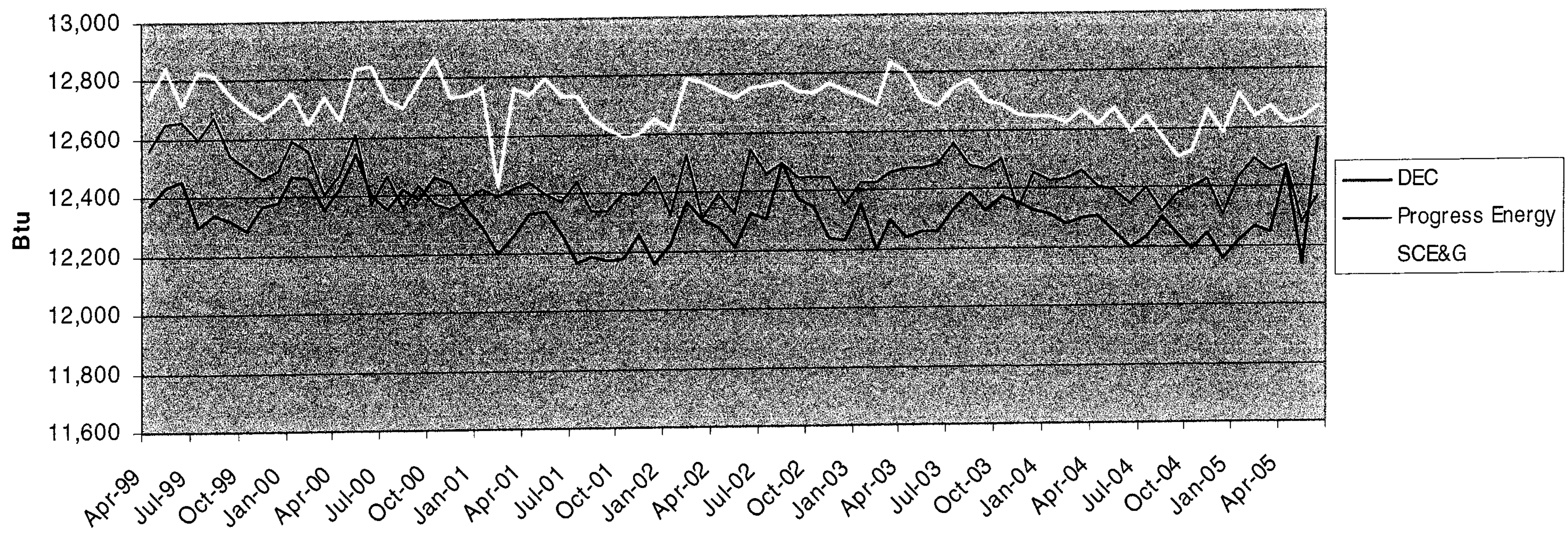
ATTACHMENT H

Graph 7 - Delivered Cost (4/99 - 6/05)



ATTACHMENT I

Graph 8 - Btu of Delivered Coal



ATTACHMENT J

Duke Energy Carolinas Fuel Study
INVENTORY TRACKING (TONS)
REVIEW PERIOD: (1/1/2005 – 12/31/2005)

REDACTED

Duke Energy Carolinas Fuel Study
INVENTORY TRACKING (TONS)
REVIEW PERIOD: (1/1/2006 – 12/31/2006)

REDACTED